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WILLIAM J. MURPHY, PE

CONSULTING ENERGY

September 27, 2004

Docket Control
Arizona Corporation Commission
1200 West Washington
Phoenix, AZ, 85007

TESTIMONY OF AzCA/DEAA UNDER DOCKET NO. E-01345A-03-0437

Dear sir or Madam:
Attached pls find the filing of testimony in the above mentioned Docket.
The witnesses for AzCA are:

Bob Baltes
Bill Murphy
Peter Chamberlain

Arizona Corporation Commission
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Sincerely,

William J. Murphy

William J. Murphy P.E.
VP of Arizona Cogeneration Association

Cc. Docket Control (original plus 30 with attachments)
Parties of Record (by email).

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SETTLEMENT AGREEMENT

DIRECT TESTIMONY OF ROBERT T. BALTES ON BEHALF OF THE ARIZONA COGENERATION ASSOCIATION.

(DOCKET No. E-01345A-03- 0437)

INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is Robert T. Baltes, and my business address is 9601 N.19th Street, Phoenix, AZ 85020.

Q. BY WHO ARE YOU EMPLOYED AND WHOM DO YOU REPRESENT IN YOUR TESTIMONY?

A. I am an individual and I am working on behalf of the Arizona Cogeneration Assn, (AzCA), and DBA Distributed Energy Association of Arizona (DEAA).

Q. WOULD YOU PROVIDE SOME INFORMATION ON THE AzCA AND DESCRIBE THEIR INTEREST IN THIS PROCEEDING?

A. The AzCA is a nonprofit coalition of interested parties organized for the purpose of exchanging information on distributed generation and advocating for policies that permit safe, reliable and economically viable use of distributed types of generation. AzCA members represent utilities customers, gas and electric utilities, environmental consultants, developers and energy industry consultants. AzCA has interest in this proceeding due to the impact the proposed rates would have on customers in terms of their energy budgets as well as their ability to effectively implement and derive economic and operational benefits from a wide range of distributed generation (DG) alternatives in Arizona.

Q. WOULD YOU DISCUSS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE?

A. I attended schools in Wisconsin and received a BS degree in electrical engineering from the University of Wisconsin in 1961. I founded Baltes/Valentino, Ltd (including predecessor companies) in 1972, which was sold in 2002. I became interested in Energy issues and Cogeneration in 1968 while working for an Iowa consulting engineering company. During the years at BVA, I designed many Cogeneration facilities that operated in Arizona such as the Phoenician Resort's system. I remain a Certified Cogeneration Professional and a Registered Professional Engineer while I continue to educate people that are interested in alternative energy, and especially 'Renewable Energy' alternatives. I presently serve as President of the Distributed Energy Association of AZ (DEAA). I am a past Chairman of the Cogeneration Committee for the American Consulting Engineers Council (ACEA) and a founding member of the Arizona Cogeneration Association (ACA). Also, I served on the AZ Technical Board of Registration. I provided energy information consultation services for many, business, governmental, and educational organizations including: The Arizona Department of Administration, Arizona Corporation Commission, Arizona State University, Northern Arizona University, Arizona Western College, Maricopa Community Colleges, City of Phoenix & ADOT.

Q. WAS YOUR TESTIMONY AND ACCOMPANING EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes.

Q. WOULD YOU SUMMARIZE YOUR TESTIMONY?

A. My testimony focuses on the necessity for a fair and equitable Interconnection Agreement for Distributed Generation (DG). The Interconnection must be safe but easy with a Pre-certified and Standardized process that reflects the true net costs of interconnection. DG of 2,000 kW and below should be subject to a standard ACC agreement, which would entitle DG's to interconnect with the distribution system and such an agreement be completed in a reasonable and predetermined time frame. The cost of the any necessary utility study must be capped the standard agreement.

Standard interconnection procedures limit opportunities for public utilities that own both generation and transmission to favor their own renewable generation and/or favor such facilities with subsidized lower rates. These standards help produce just and reasonable interconnection charges for DG's.

Q WHY SHOULDN'T WE PROPOSE THE EXISTING FERC 104 paragraph 61,104 BE ADOPTED IN WHOLE OR PART AS BEING THE AZ STADARD?

A The FERC regulation deals with low voltage as being 69KV and lower. This is called their so-called Small Generator Interconnection regulations. DEAA believes this Commission should recognize 12.7 KV and below as a separate category. DEAA has most all its activity needing to connect to voltages 12KV and below.

CONNECTABILITY OF THE DISTRIBUTION SYSTEM

The distribution system is made up of small 12.7 kV and lower voltage distribution lines that serve loads with totals of less than 10MW. These are basically one-way (radial) lines are both underground and overhead in construction.

HOW CAN CUSTOMERS REDUCE THE COST OF THEIR ELECTRICAL CONNECTIONS?

Here are some of the methods:

1) Move the business closer to a substation.
2) Add another separate 12.7 kV "feeder", with automatic transfer capability. This is very expensive and may benefit others, so this factor must be credited against the interconnect cost.
3) The customer can install his own Distributed Generation feeder in parallel with the Utility. This can help both the customer and the Utility and may benefit other customers near the new line so this factor must be credited against the interconnect cost.

PRICING CONCEPTS

The pricing of the interconnection must be fair and accurate. It must be detailed in an industry standard form so as to be understood by another cost estimating professional. Cost items must be separated into the smallest items. Items cannot be lumped together otherwise the estimate is difficult to verify.

The best answer remains to standardize the interconnect to avoid reinventing the interconnection each and every time.

The cost of any necessary utility study must be capped as part of the standards so the real cost of the interconnection is determinable at an early stage.

WHAT DOES YOUR ORGANIZATION WANT FROM THIS HEARING?

We want to have pricing mechanisms that do not punish customers who employ DG to increase the Utility electrical service reliability or that reduce the customer's electrical operating costs.

We believe the pricing signals should encourage Distributed Generation.

These pricing mechanisms must include rates and associated interconnection standards to that end.

DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

Yes.

SETTLEMENT AGREEMENT

DIRECT TESTIMONY OF WILLIAM J. MURPHY ON BEHALF OF THE ARIZONA COGENERATION ASSOCIATION.

(DOCKET No. E-01345A-03-0437)

INTRODUCTION AND SUMMARY

Q. PLEASE STATE YOUR NAME AND BUSINESS ADDRESS

A. My name is William J Murphy, and my business address is 2422 E. Palo Verde Drive, Phoenix, AZ 85016.

Q. BY WHO ARE YOU EMPLOYED AND WHO DO YOU REPRESENT IN YOUR TESTIMONY?

A. I'm with Murphy Consulting and am working on behalf of the Arizona Cogeneration Assn, (AzCA), DBA Distributed Energy Association of Arizona.

Q. WOULD YOU PROVIDE SOME INFORMATION ON THE AzCA AND DESCRIBE THEIR INTEREST IN THIS PROCEEDING?

A. The AzCA is a nonprofit coalition of interested parties organized for the purpose of exchanging information on distributed generation and advocating policies that permit safe, reliable and economically viable use of distributed generation. AzCA members represent utilities customers, gas and electric utilities, environmental consultants, developers and energy industry consultants. AzCA has a direct interest in this proceeding. The proposed rates impact customers in terms of their energy budgets as well as their ability to effectively implement and derive economic and operational benefits from a wide range of distributed generation (DG) alternatives in Arizona.

Q.WOULD YOU DISCUSS YOUR EDUCATIONAL BACKGROUND AND BUSINESS EXPERIENCE.

A. I attended Grammar, High School, and College in Arizona. I received a BS in Engineering from the University of Arizona, after attending, Phoenix College, Regis University, & Arizona State University.

I worked for a number of small and large businesses in Arizona and California before joining Arizona Public Service (APS). During my 16 years with The Company, I served on the various committees including the Totalizing Committee, the Load Forecast Committee, and the Cogeneration Committee. I Left the utility Manager of Power Contracts, and then operated an energy Consulting firm named Murphy Engineering for 16 years. ME provided energy and utility rate consultation services for many, business, utility, governmental, and educational organizations including: The Arizona Energy Office, Arizona Department of Administration, Arizona Corporation Commission, RUCO, University of Arizona, Northern Arizona University, Arizona Western College, ADOT, Arizona Interfaith Coalition on Energy, Arizona Cotton Growers Assn., Cyprus Mining, Arizona School Boards Association, many school districts including Phoenix , and Scottsdale, and most of the Cities in the Valley., and others.

I also served as the "Energy Manager" for the City of Phoenix from 1992 until 2003. And during this time I oversaw and became familiar with the Cities 3,000 individually metered electric (industrial, commercial, and residential) accounts.

I also developed an in-depth view of the range of understanding of utility rates held by the many employees that interact with the utility billing.

Q. WERE YOUR TESTIMONY AND ACCOMPANING EXHIBITS PREPARED BY YOU OR UNDER YOUR DIRECTION?

A. Yes, except for the attached graph, I prepared all of my testimony.

Q. WOULD YOU SUMMARIZE YOUR TESTIMONY?

A. My testimony focuses on the proposed changes to the APS General Service (GS) Rates E-32, E-32R, and E-52. Specifically the proposed rates discourage customers from generating their own electricity utilizing renewable and non-renewable energy sources.

Historically, in the United States, pricing of most products are the result of the influence of "supply and demand". But in some utility sectors, in exchange for a state granted monopoly, state regulatory bodies approve and regulate revenue levels and pricing mechanisms.

Unfortunately some rates in use are not well suited to today's economic situation. Better, more useful forms of pricing including Time of Use (TOU), Real Time Pricing (RTP), and Critical Peak Pricing (CPP), were neither encouraged nor included in the Settlement Agreement.

Instead the Settlement Agreement proposed Demand/Energy rates decrease the economic benefit at a time when these DG technologies are more needed for multiple reasons. Those include the application of self-generation to increase Customer's reliability, quality of their electricity delivered, reduce emissions, and improve efficiency of energy use.

Recently the World-wide sea change in the cost of fossil fuels is occurring. In Arizona this is evident in the 3 fold increase in price of pipeline natural gas. This at a time when Arizona has built (& hosted) more natural gas fired electric generation the all of the generation that existed in AZ before. The pricing terms of the Settlement ignore this significant change.

Customer built Distributed Generation is not funded by the utility or subsidized by other customers. Instead customer financing benefits both the specific customer and all customers by firming up the distribution and transmission systems. The diverse nature of these small generators removes rate and fuel adjustment increases by shifting the responsibility to specific customers.

DG also raises the issue: How can Arizona prepare for a future that is not so reliant on imported oil and natural gas? It is our belief that a sustainable electric future of Arizona could be created by a joint collaboration of the electric utility, the ACC, and customers.

TRANSMISSION SYSTEM RELIABILITY

Last August (2003) this Country experienced the largest multi-state electrical outage in United States history. This has caused a major call for improvement in the Nation's transmission grid.

Very Large, and Large GS customers who receive their electricity at transmission level will have 100% of their outages caused by the electric transmission/generation system.

TRANSMISSION/DISTRIBUTION SYSTEM RELIABILITY

Medium and small GS and residential customers who receive their electricity from both the transmission & distribution system will generally suffer the same outages as the Large customers mentioned above.

But, these smaller customers will also suffer outages that are caused by the distribution system outages in addition to the outages caused by the transmission system

Unfortunately these distribution outages are much more numerous than the transmission outages.

RELIABILITY OF DISTRIBUTION SYSTEM

The distribution system is made up of numerous 12.7 kV distribution lines that connect substations to the customers. They generally can serve total loads of less than 10MW. These lines are both underground and overhead in construction. The overhead (O/H) lines suffer more outages the underground (U/G) lines.

WHY IS INTEREST IN RELIABILITY OF THE ELECTRIC SYSTEM OF INCREASING?

Today's businesses are employing many more electronic devices (from cash register scanners to variable speed drives and machine controls) that react in varying ways to sags, surges or even brief power outages. Residential customers experience similar problems characterized by flashing VCR clocks.

With today's increasing business use of electronic process controls, and other electronic devices, electric outages are becoming more disruptive as the outages interrupt business operations.

HOW CAN CUSTOMERS INCREASE THEIR BUSINESS'S ELECTRICAL RELIABILITY?

: Following are some of the more economic methods are:

1) Move the business closer to a substation. Very expensive.
2) Add another separate 12.7 kV "feeder", with automatic transfer capability. This can be expensive, and may benefit others.
3) Add an Uninterruptible Power Supply system (UPS). This too is expensive, increases operating costs, and is not always reliable.
4) Install his own Distributed Generation in parallel with the electric grid. This would help both the customer and the Company with reliability.

NEWER PRICING CONCEPTS

Electricity pricing is still patterned after the way Tom Edison did it over 100 years ago! I understand he billed for the total number of lamps and total kWh. This was his version of a demand/energy rate.

Today due to the dominance of cooling load in the desert, Arizona could develop a huge summer loads. This can prove to be an economic burden.

We need to implement other pricing concepts, including RTP, and CPP, and even TOU. These pricing formats need to be explored before the summer peak load grows too large to manage.

See the attached graph filed earlier by ACC Staff witness Erinn Andreasen. It provides a clear picture of the APS load shape, with its associated ramifications.

WHAT DOES YOUR ORGANIZATION WANT FROM THIS HEARING?

We believe the pricing signals should encourage Distributed Generation. .

These pricing mechanisms must include rates and associated interconnection standards to that end.

The rate and interconnection issues are also covered in Mr. Chamberlain's and Mr. Baltes' testimony.

DOES THIS CONCLUDE YOUR DIRECT TESTIMONY?

Yes, it does.

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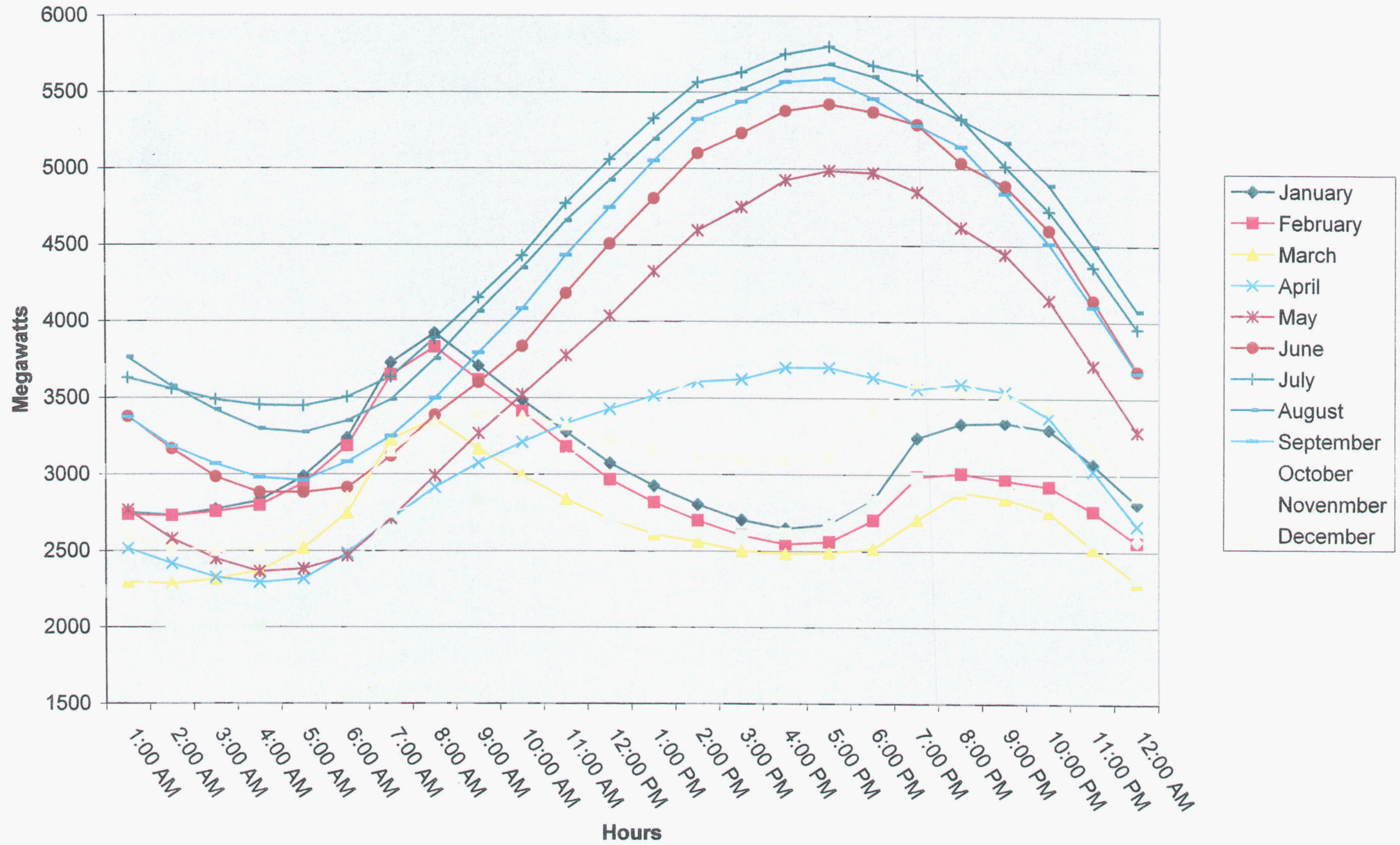
APS Peak Day Load Curve 2002



SETTLEMENT AGREEMENT

DIRECT TESTIMONY OF PETER F. CHAMBERLAIN ON BEHALF OF THE ARIZONA COGENERATION ASSOCIATION

(DOCKET No. E-01345A-03-0437)

Q. Please state your name and affiliation.

A. My name is Peter F. Chamberlain, dba Chamberlain Energy Consulting. My office address is 215 East 79th Street, New York, NY. I am representing the Distributed Energy Association of Arizona (DEAA) in this proceeding.

Q. Please state your background and expertise.

A. I have worked in energy-related fields for over 20 years. I have been employed by Stone & Webster Engineering Corporation, Westvaco Corporation and BOC Gases Company. I am currently an independent energy consultant, working primarily in the development of competitive wholesale electric markets and the creation of standardization efforts for the interconnection and operation of distributed resources, including technical, contractual and process standards and the development of appropriate rates for standby service.

I have testified in many state regulatory proceedings in California, West Virginia, Virginia. Maine, and Maryland. I have testified before the FERC on several occasions and before the Energy Subcommittee of the US House of Representatives.

I have negotiated numerous rates and contracts for electric supply, including standby, maintenance and supplemental service, as well as purchase power agreements for cogeneration facilities. I have testified on numerous occasions on the subject of rate design and cost allocation.

I have actively participated on behalf of distributed resources in the development of wholesale market mechanisms that accommodate market entry for distributed generation and other demand response resources into the wholesale markets. These

4. **The proposed settlement offers no opportunities for on-site generation to receive compensation for the value they do or could provide to the APS system.**
5. **The proposed settlement makes no provision for the expeditious adoption of meaningful interconnection standards and procedures which incorporate and implement standards contained in IEEE 1547.**

Q. Does the Settlement provide for rates for standby, supplemental, and maintenance service for general service customers taking or wishing to take partial requirements service?

A. Yes. As examples, rate schedules E-32R and E-52 have provisions that allow E 32 customers to operate generation to meet part of their respective loads. I will, as Mr. Murphy has done, focus my comments on small, medium General Service customers with loads less than 3000 kW.

Q. Do these rates reflect the costs of providing backup and maintenance service to partial requirements customers?

A. No, they do not. Both the rates themselves and the manner in which they are applied to a partial requirements customer's load drastically over-recover the costs of providing service. The rates fail to reflect the manner in which the system is planned and, importantly the realities of the existing generation and transmission system.

Q. How do fully integrated utility systems – such as APS – plan system generation and transmission capacity additions?

A. A fully integrated utility system plans generation and transmission capacity to meet its system peak load. A utility estimates what aggregate customer loads will likely be at the system peak. The generation and transmission requirements needed to provide a reliable system are determined based on the estimated system peak load, taking into account many factors, including generation and transmission availability, contingency analysis, planned maintenance and transmission congestion. Planning to meet the system peak inherently reflects the diversity of the loads. That is, how much of the connected load is likely to be on-line at the time of the system peak. For a high load factor customer, it is very likely that most or all of its load will be on line at the time of the system peak. This customer would provide little load diversity to the system and the utility would be compelled to build capacity to meet most of the customer's load at the system peak.

Q. How does a utility plan its G & T systems to meet peak loads of low load factor customers?

A. That depends on the customer's usage profile. If a general service customer's usage is likely to occur at the system peak (because of hours of operation, weather dependency, or other reasons) then a utility must plan its G&T system to meet that customer's peak load. However, a customer that normally self-generates its own load requirements – requiring only standby and maintenance service when its generator is planned or forced off line – is far less likely to require electric energy at the time of the utility's system peak. In fact, if rates – particularly energy rates – are properly priced, a customer will have a significant incentive to generate its own power at the time of the system annual or monthly peaks – avoiding high cost peak energy.

Q. Do integrated utilities count on diversity in planning generation requirements?

A. Absolutely. If they did not, they would have to have twice the capacity needed to serve its peak load reliably. Instead, they build to meet peak plus a reserve margin to account for generation forced and maintenance outages. Reserve margins are typically 15% to 25% of a system's peak load forecast. This is a reasonable range within which to establish the amount of generation and transmission capacity a utility would need to meet a small generator's standby power loads.

Q. Do the rates in the proposed Settlement reflect these lower capacity requirements needed to provide standby service?

A. No, they do not. In fact, in some cases they may even assign more cost responsibility for generation and transmission capacity to standby customers than to full service customers. This has the effect of (improperly) keeping customers from making investments in otherwise cost-effective generation investments.

Q. Which existing and potential FERC Qualifying Facilities (QFs) may be most affected?

A. Because APS is proposing that largely variable rate components for standby service be replaced by largely fixed rate components, smaller renewable generation like solar, wind and hydro are impacted the most , in a relative sense.

Q. Is the proposed E-32/E-32R rate structure an appropriate cost-based rate for partial requirements customers?

A. No, it is not. For that matter, I do not believe that is suitable for a full service customer either, although I will restrict my discussion to E-32's application to partial requirements customers.

Q. Does E-32/E-32R account for any diversity in its proposed rate structure?

A. Just the opposite. These rate designs essentially assume that there is no diversity, as they recover G & T charges based on a standby customer's highest level of standby demand, whether it occurs at the system peak or not - even if it occurs during off-peak hours. Under the proposed rate E-32, a partial requirements customer has little or no economic downside to taking standby service at the time of the system peaks.

Q. Do other jurisdictions recognize the diversity of peak system loads?

A. Yes. For example, in Con Edison's service territory, the standby rate for a primary customer assesses transmission charges based on a daily basis based on peak period demand levels during the month. In addition, a standby customer's installed capacity requirement is based on its load during the hour of the Con Ed's system peak. In Contrast, E-32 assesses generation demand based on a standby customer's monthly peak – anytime during that month or year.

Q. Would a Con Ed customer pay more for standby than under the proposed E-32?

A. Amazingly, no. Con Ed is one of the highest cost utilities in the country and offers standby rates that are LESS than the proposed APS rates for partial requirements customers under reasonable operating conditions.

Q. How is this possible?

A. Take, for example, two 500 kw standby customers with identical load profiles – one on Con Ed's system and one on APS's system. Each customer normally supplies all of its load from its own generation and requires standby service for one on-peak hour every month. The result of applying both rates to this load profile is that the standby customer taking service under E-32 would pay more annually than the identical load on Con Ed's SC-14-RA rate schedule – a rate already viewed as uneconomic by many project developers.

Q. Are there other public policy concerns with E-32/E-32R?

A. Yes. First, E-32 is commonly referred to as a "load factor" rate. E-32 has been designed to take costs that have been "functionalized" as energy and apply them to a rate design that virtually guarantees cost recovery from EVERY customer. This is accomplished by defining an energy "block" as a function of the customer's peak monthly usage – irrespective of whether that peak occurred during peak or off-peak hours – multiplied by a very low amount of hours of use (200 hours) per month.

Thus, these rates effectively refunctionalize energy costs and make them demand based by "loading up" the first energy block of this load factor rate in a manner designed to recover all non fuel variable costs based solely on a customer's non-coincident monthly peak demand. An E-32 customer operating solely during off-peak hours with a peak load of 500 kw would pay the same total demand and non-fuel energy charges as a customer operating during only on-peak hours.

Q. Is that a desirable result?

A. I can't see how. It is my impression that there is considerable concern amongst policy makers about the long-term adequacy of generation and transmission capacity on the APS system. The problems experienced this past summer with the loss of the Westwing transformer bank highlight those concerns and suggest that the existing system is capacity deficient TODAY. The need for voluntary load shedding in the Phoenix load pocket upon a single failure event seems to indicate a less than reliable transmission system.

Q. Why do you believe that the system may already be inadequate?

A. It is a customary practice that reliability councils around the country require that a system be able to meet expected load under a "single contingency" condition. That is, a reliable system should be able to meet its customer loads even with the loss of a single major transmission or generation facility. I believe that the loss of the transformer bank this past summer would constitute a single contingency failure and a reliable system would not have needed to rely on voluntary load reduction to meet its total demands as was the case this past summer. The electrical transmission area around Phoenix has been described as a "load pocket" – that is, the transmission capacity feeding the area is insufficient to reliably serve the load without generation electrically located in the load pocket.

Q. Is this a situation unique to Phoenix?

A. No. Load pockets exist in many locations. New York City is a load pocket. Load serving entities serving load in NYC are required to purchase at least 80% of their respective capacity requirements from generators electrically located in NYC. This is referred to as a "locational capacity requirement." As a result of the limited transmission import capacity into NYC, generation in NYC is more valuable than generation outside of the City.

The New York State Reliability Council (NYSRC) sets the state's annual reserve margin requirements based on the 80% in-City capacity requirement.

Q. Does Phoenix have a similar locational capacity requirement?

A. Not that I am aware of. The need for locational capacity, however, is evident by the designation of "must run" units within the Phoenix load pocket.

Q. Does a load factor rate, such as E-32, create incentives for voluntary load reductions?

A. No. In fact, the customer that voluntarily shifts load from peak periods to off-peak periods, would likely experience significant cost penalties for doing so. This would occur if shifting usage to off-peak hours actually caused the off peak demand level to exceed the normal peak period demand level. For example, a customer might be operating around the clock at relatively high load factor – incented by the E-32 rate structure. By agreeing to voluntarily shed load to support the system, the customer might increase production and electric usage during off-peak hours to make up for production lost during its voluntary load reduction. Thus, the customer would experience an off-peak demand level that was greater than its otherwise normal monthly peak. This would increase the customer's demand charges AND increase the number of kWhs allocated to the first block of energy where a grossly disproportionate amount of variable energy-related costs are recovered.

Q. Doesn't that mean that a customer that voluntarily shed load to support the system that should have been able to sustain the loss of the transformer bank could have experienced a significant economic penalty for doing so?

A. Absolutely. Under E-32, "no good deed goes unpunished."

Q. Do you believe that E-32 rates are cost-based?

A. No, for several reasons. First, as discussed earlier, the rate essentially treats variable no-fuel energy costs like demand costs and recovers them based on peak demand (albeit through a kwh charge designed to recover all non-fuel costs in the first energy block – the amount of those kWhs being determined by monthly peak demand.)

E-32 recovers generation and transmission costs based on customer's non-coincident peak demands. As discussed earlier, generation and transmission capacity is planned to reliably meet the system peak – NOT the sum of the system's connected loads. As a result, a customer has no clear incentive to avoid consumption at the system peak. A customer operating exclusively during off-peak periods pay essentially the same charges as a similar customer operating exclusively during on-peak hours.

Q. Are the partial requirements tariffs based on cost of service principles?

A. No. The de facto application of full service rates to back-up and maintenance service grossly distorts the cost of providing service to partial requirements customers by assuming that they have load profiles similar to full service customers.

Q. Is that a reasonable assumption?

A. No, it is not. APS fails to assume the realistic diversity of standby customers. The proposed rate designs ignore the near-impossibility that all partial requirements customers would be taking their full standby service at the same time and at each monthly system peak.

Q. Is this allocation consistent with WESTCONNECT's Open Access Transmission Tariff (OATT)?

A. No, it is not. WESTCONNECT employs different assumptions in the development of its Open Access Transmission Tariff (OATT) rates than APS does in the development of its proposed standby rates. That is, WESTCONNECT's OATT rates are developed assuming that monthly peak loads vary from month to month. In contrast, it appears that APS developed its standby rate proposals assuming that standby customers require a constant amount of transmission service (based on its annual, non-coincident peak load) all year long and that ALL standby customers need service at the same time on-peak..

Q. Does APS allocate transmission costs to E-32 customers in the same manner WestConnect does under its Open Access Tariff?

A. No. E-32 customers are allocated transmission cost responsibility in a manner that is inconsistent with WestConnect's FERC approved transmission rates. Many of WestConnect's FERC approved OATT charges are collected through a kWh charge – rather than through a kw charge, as E-32 does. Even where the tariff employs a per kw, charge that is based on each Scheduling Coordinator's total retail load's contribution to the MONTHLY peak hour load in a given month. In the extreme example, an SC that has only off peak customers would not incur per-kW transmission charges under the WestConnect tariff. However, those same retail customers served by the SC and taking service under E-32 would pay per-kW charges as if they all consumed their respective monthly peak loads at the time of the monthly system peak - clearly not a cost-based result.

Q. **Are there other inconsistencies between E-32 and the WestConnect tariff?**

A. Yes, a potentially significant one that could lead to significant over-recoveries by APS. The WestConnect tariff assigns kw-based transmission cost responsibility based on monthly peak HOURLY usage. In contrast, E-32 and other retail tariffs assign transmission cost responsibility on the highest 15 minute period at ANY TIME during the month – normalized to an hour by multiplying times four (4).

Thus, even if all partial requirement customer's load did occur simultaneously at the monthly system peaks – an assumption with which we vigorously disagree – APS would still bill more transmission kws under E-32 because the 15 minute peak kw measurement in the retail tariff will always be higher than the 60 minute kw measurement in the WestConnect RTO tariff.

And, because E-32 is a load factor rate, APS will also over-recover additional charges for transmission that may be contained in the first block of the energy rates.

Q. Do partial requirements customers suffer disproportionately under this improper allocation of generation and transmission costs?

A. Yes.

Q. Are FERC-approved transmission charges always applied on a kW basis?

A. No. In fact, both PJM and the New York Independent System Operator (NYISO) calculate their respective OATT charges on a MWh basis for firm service. There are no associated demand charges. A transmission customer pays as he goes. Thus, a 5% load factor customer would only pay for the MWh consumed and not be forced to pay a ratcheted demand charge based on its annual non-coincident peak.

Q. Are there other concerns with the design of E-32?

A. As discussed more fully in Mr. Murphy's testimony, it seems likely that the kwh rate for tailblock kwh will NOT recover the ACTUAL variable fuel costs of generation – let alone variable O&M costs and other energy-based costs. If this indeed the case, then it suggests that rates for energy in the first block of kwh may be designed to recover the shortfall of fuel costs that are not going to be recovered in the tailblock rates.

Q. Should retail rates ever be designed to knowingly under-recover variable fuel costs?

A. No. In over twenty years of experience in the industry, I cannot recall a single instance where a kwh charge intended to recover fuel costs was set below the expected average cost of producing that kwh. The E-32 rate design promotes incremental energy usage after the 200 kwh per kw block is met. If the tail block energy rate is below expected costs, then its usage is being subsidized by others. In the competitive world, below-variable cost pricing can be the subject of anti-trust inquiries.

Q. Isn't this incremental tailblock usage likely to come from coal or nuclear units with low operating costs?

A. No. Witness Wheeler of APS indicated in his testimony that the base load (coal and nuclear) units had reached their maximum energy output (Wheeler at p. 11, lines12-16). As a result, any shift to off-peak usage would have to be met primarily by gas fired units and, as discussed, by Mr. Murphy, it seems unlikely that the tailblock rates in E-32 cover even the actual fuel costs incurred to generate using natural gas. Even if the cost of providing tailblock energy ON AVERAGE was less than the incremental cost of gas generation (because of a mix of coal, nuclear and gas generation), it would still improperly send the signal that <u>incremental</u> tailblock usage could be supplied at prices below the actual costs of incremental gas generation. This would virtually guarantee an under recovery of direct fuel expenses – assuming that these under recoveries had not already been allocated to the kwh charges in the first energy block.

Q. In your opinion, does E-32 TOU address the concerns you expressed regarding E-32 as they apply to partial requirement customers (PRCs)?

A. No. I do not believe that E-32 TOU is a time-of-use rate at all. Referring to the bundled service for loads greater than 20 kw, the sole time-of-use impact is contained in a mere 1 cent difference between peak and off peak energy prices in the summer months. Demand charges are applied to peak usage occurring anytime during the month. Moreover, demand prices for transmission and distribution are inexplicably and drastically reduced for load in excess of 500 kw without any cost basis and inconsistent with the WestConnect tariff charges – which do not offer discounts for transmission service in excess of 500 kw.

Q. Can on-site generation provide generation and capacity benefits to the electric system?

A. Absolutely. Indeed, as reported in the local newspaper, several customers' generating facilities provided critical capacity during the transformer outage this past summer. To my knowledge, that capacity value was not compensated for the value it provided during critical peak load periods. To my knowledge, there are no existing mechanisms available for doing so. Moreover, those customers offering this needed system support may have actually experienced an increase in their cost of electricity because of the rate design flaws discussed earlier.

Q. Do other jurisdictions compensate customers for the value of their respective generation?

A. Yes, in New England, New York and on the PJM system, customer generation can be sold in the market at the going rate for generation capacity. In New York, reliability studies and required reserve margins factor in customer-owned resources as being available to meet system peaking requirements.

Q. Do the APS rates in this Settlement have any provision to compensate customer generation for being available during system peaks?

A. To my knowledge, no. In fact, it may be in a customer's interest to shut its generator down during peak periods because of the perverse outcomes attributable to the load factor based energy rate in E-32. That would occur as soon as the customer's kwh usage exceeded the product of its peak demand and 200 hours. Once a customer gets past the first energy block, the incremental cost of purchasing electricity drops below its probable cost of generation under the rates proposed.

Q. What should this Commission due to further the standardization of small scale generation to its distribution system?

A. With the passage of IEEE 1547, the Commission now has a recognized tech standard around which rules and procedures can be easily developed to streamline interconnection requests. This is desperately needed if small scale generation is to reliably connect to the APS system.

A number of states have embraced IEEE 1547 – Massachusetts, Nevada, New York – while others, including Texas and California, have developed standards and procedures before the ratification of 1547 that are very much consistent with it.

It must be noted that IEEE 1547 is only a technical standard and there is much "meat that needs to be put to the bone" to effect a successful standardization program. I believe that this could be accomplished in a reasonably short amount of time with the active participation and encouragement of Staff and drawing upon the work that has already been done in other states.

Q. Does this conclude your testimony?

A. Yes, it does.